Cinch Energy Corp. | 2006 Annual Report

Cinch Energy Corp.

Corporate Profile

Cinch Energy Corp.'s mission is to grow both production and reserves on a capital efficient basis through exploration/development and strategic acquisitions. Management's goal is to maximize shareholder value, enhancing both the net asset value and cash flows of the Company, while continuing to be a responsible and upstanding corporate citizen.

Abbreviations

$M	thousand dollars
ARTC	Alberta Royalty Tax Credit
bbl	barrel
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrel of oil equivalent
boepd or boe/d	barrel of oil equivalent per day
btu	British thermal unit
bw/d	barrels of water per day
Cdn	Canadian
Established	total proved plus 50% of probable
GJ	gigajoule
GJs/d	gigajoules per day
mbbls	thousand barrels
mboe	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbbls	million barrels
mmboe	millions of barrels of oil equivalent
mmbtu	million British thermal units
mmcf	million cubic feet
mmcfpd or mmcf/d	million cubic feet per day
NGLs	natural as liquids

Annual General and Special Meeting

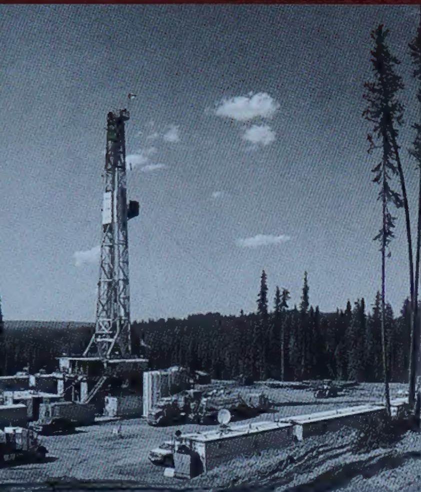
The Annual General and Special Meeting of Cinch Energy Corp. will be held in Great Room 3 at The Sandman Hotel, 888 - 7th Avenue SW, Calgary, AB T2P 3J3 on May 16, 2007 at 2:30 PM. We encourage all shareholders to attend.

Contents

About the Cover

This year's annual report cover features a painting of the Cinch logo by Paul Van Ginkel. For more information on the artist, please visit www.paulvanginkel.com

Highlights



From Left:
Ron Peshke, Engineering Manager
Larry Baker, Drilling and Completions Manager

	Three Months Ended December 31,		Year Ended December 31,	
	2006	2005	**2006**	2005
	Unaudited	*Unaudited*		
Petroleum and natural gas sales, net of transportation ($000's)	**5,733**	8,323	**20,112**	27,413
Production per day				
Natural gas (Mcf/d)	**6,500**	6,248	**5,851**	6,478
Natural gas liquids (Bbl/d)	**236**	203	**207**	217
Equivalence at 6:1 (BOE/d)	**1,320**	1,245	**1,182**	1,297
Sales Price				
Natural gas ($/Mcf)	**7.49**	12.44	**7.14**	9.59
Natural gas liquids ($/Bbl)	**57.56**	62.69	**64.53**	59.83
Equivalence at 6:1 ($/BOE)	**47.22**	72.68	**46.62**	57.90
	$	$	**$**	$
Funds from operations (000's)(1)	**2,970**	4,899	**9,966**	15,042
- per share, basic (1)	**0.06**	0.10	**0.21**	0.38
- per share, diluted (1)	**0.06**	0.10	**0.20**	0.36
Net income (000's)	**(488)**	1,364	**(317)**	3,364
- per share, basic	**(0.01)**	0.03	**(0.01)**	0.08
- per share, diluted	**(0.01)**	0.03	**(0.01)**	0.08
Capital expenditures ($000's)	**9,324**	11,982	**36,966**	36,045
Basic weighted average shares outstanding (000's)	**47,813**	47,813	**47,813**	40,047
Working capital (net debt)(2) ($000's)			**$**	
As at December 31, 2006			**(23,745)**	
As at December 31, 2005			**3,490**	

	As at March 7, 2007(3)
Common shares and special warrants outstanding	**55,625,132**
Options outstanding	**4,078,000**
- average exercise price	**1.95**

(1) Funds from operations is not a generally accepted accounting principle ("GAAP") measure and represents cash provided by operating activities on the statement of cash flows less the effect of changes in non-cash working capital related to operating activities.
(2) Net debt is a non-GAAP measure and represents the sum of the working capital (deficiency) and the outstanding credit facility balance.
(3) Subsequent to December 31, 2006, the Company issued, for gross proceeds of $10 million, a total of 7,812,500 common shares on a flow through basis at a price of $1.28 per common share.

Letters to the Shareholders

From Left:
George Ongyerth, President
John W. Elick, Chairman & Chief Executive Officer

MESSAGE FROM THE CHIEF EXECUTIVE OFFICER

Once again, I thank you for your interest and your investment in Cinch. I welcome you as a shareholder and although we've been through a tough year, we remain very positive about the future for several reasons:

- For the most part, our very strong management team is still intact in this tight employment market. We have had one change, and that is the addition of Ron Peshke, P.Eng., as our Manager of Engineering.
- After the unusually warm winter in 2006, which caused the sharp decline in natural gas prices, in 2007 the weather has to date been back to normal and gas prices have firmed as storage levels started to decrease.
- Our land holdings, in our core areas in the Deep Basin of Alberta, are still a major asset and have huge potential for a major discovery. We plan to drill more wells here this year.
- Our production base grew again last year and production from the good wells in this area has remained strong for several years.

In summation, with our strong staff and excellent land position, focused in the Deep Basin, and our strong balance sheet, we look forward to a "breakout" year.

"It's a Cinch"!

John W. Elick

John W. Elick
Chief Executive Officer

MESSAGE FROM THE PRESIDENT

In 2006, Cinch continued its exploration program in its core area of Chime and Kakwa, along with pursuing opportunities in other areas. A total of 17 wells (5.8 net) were participated in, of which 11 wells (3.2 net) were cased as potential gas wells, and 2 wells (0.9 net) were cased as potential oil wells. The Company participated in a significant gas discovery at Resthaven, which commenced natural gas production in November at 6.5 mmcfpd along with significant natural gas liquids from one zone. Another zone within the well bore tested at similar rates. The operator will be commingling the production from these zones in 2007.

At Chime, a very significant gas discovery was made offsetting Cinch's acreage, which has produced at rates in excess of 25 mmcfpd of natural gas since October. The log data from this well became available in late in 2006, which along with new reprocessing techniques, has been incorporated into Cinch's 3-D seismic database. This has allowed Cinch to develop a number of prospective drill sites which are being prepared for the 2007 drilling program.

2006 Accomplishments

- Increased the reserve base by 1.1 million barrels of oil equivalent on a proven and probable basis
- Exited the year with a production rate of 1600 boepd
- Acquired additional interests in the Company's core area of Chime for $7.75 million
- Subsequent to year end, closed a flow through share financing for gross proceeds of $10 million

Trend Issues

In the last year, a trend affecting the oil and gas industry has been the impact on capital markets created by investor uncertainty in the North American economy. Capital markets and share prices of the natural resource sector have been affected by uncertainty surrounding the economic impact created by proposals relating to changes announced in October 2006 by the Federal Government that affect taxation for income trusts. This has affected the future growth strategy of the trust sector. By acquiring oil and gas assets, trusts have provided an exit strategy for many junior oil and gas companies and by virtue of the Government's announcement, their uncertain future has created a negative impact on the junior oil and gas sector's market evaluation. Our share price was also affected, as were other companies when the announcement was made in October. In addition, the Provincial Government in Alberta announced that the Alberta Royalty Tax Credit (ARTC) would be discontinued in 2007. The resource sector had been advised by Government officials previously that the industry would be given a three year notice of any changes to the ARTC program. Sudden changes to taxation policies by our governments have negative impacts on our industry and obviously capital markets. Natural gas prices also fluctuated dramatically in 2006, which caused difficulty in planning drilling programs among Cinch's partners. Notwithstanding constant change to the oil and gas industry, whether on taxation issues or commodity prices, your management remains very optimistic regarding the potential of Cinch's future prospects. Your Company continues to pursue and evaluate prospects that meet our criteria for future growth and value for our shareholders. Management currently believes that Cinch shares are undervalued.

Outlook

The 2006 year presented challenges to the oil and gas industry with natural gas prices fluctuating dramatically, particularly in the third and fourth quarters, causing many participants in the industry to reconsider and delay their drilling programs. The cost structure for all services continued to escalate, which in combination with falling natural gas prices, challenged the economic feasibility of natural gas prospects. Cinch views this as an opportunity, since the downturn in drilling is causing the service sector to lower its costs, and also services are now available to operators which were not in late 2005 and early 2006. In addition, with the drop in natural gas prices, the Company is observing new drilling opportunities becoming available from other industry partners as capital budgets are lowered. The Company remains very optimistic about the natural gas industry and has observed natural gas prices firming up in the first quarter of 2007 due to cold weather and resultant natural gas storage withdrawals.

The Company completed a flow through share financing for gross proceeds of $10 million in the first quarter of 2007, strengthening the Company's balance sheet and allowing more flexibility for the Company's 2007 drilling program. For the 2007 year, the Company is budgeting capital expenditures of $30 million. Drilling activities are weighted to the latter half of 2007.

In particular, your Company's management is looking forward to the upcoming drilling program planned for the Chime area, which may lead to significant production adds if successful, and to the new prospect and program planned in British Columbia.

Acknowledgement

Again, on behalf of the management team, I wish to thank all of our employees for their efforts and contributions throughout the year. I wish to thank members of the Board of Directors for their continued corporate guidance.

George Ongyerth
President
March 8, 2007

Operations Review

From Left:
Brian McBeath, Vice President Exploration
Marcus McLafferty, Vice President Land,
Neil Rutherford, Manager of Geophysics,
John W. Elick, Chief Executive Officer

AREAS OF EXPLORATION

During 2006, Cinch continued its exploration program in its core areas of Chime and Kakwa along with pursuing opportunities in other areas.

At CHIME, Cinch has reprocessed its 3-D seismic data over the Chime area, incorporating log data from a third party's new offsetting well, which is producing at rates in excess of 25 mmcfpd from the Falher B zone since October. The Company has identified several prospective locations and expects to commence drilling in May, weather allowing. The reprocessed seismic data indicates 3 to 5 follow up locations on this Falher trend. During 2006, Cinch operated the drilling of two wells in the Chime area, one of which was completed and tied in as a gas well. In addition, the Company acquired additional working interests in 7 producing natural gas wells for approximately $7.75 million (net) after selling the undeveloped lands thereon.

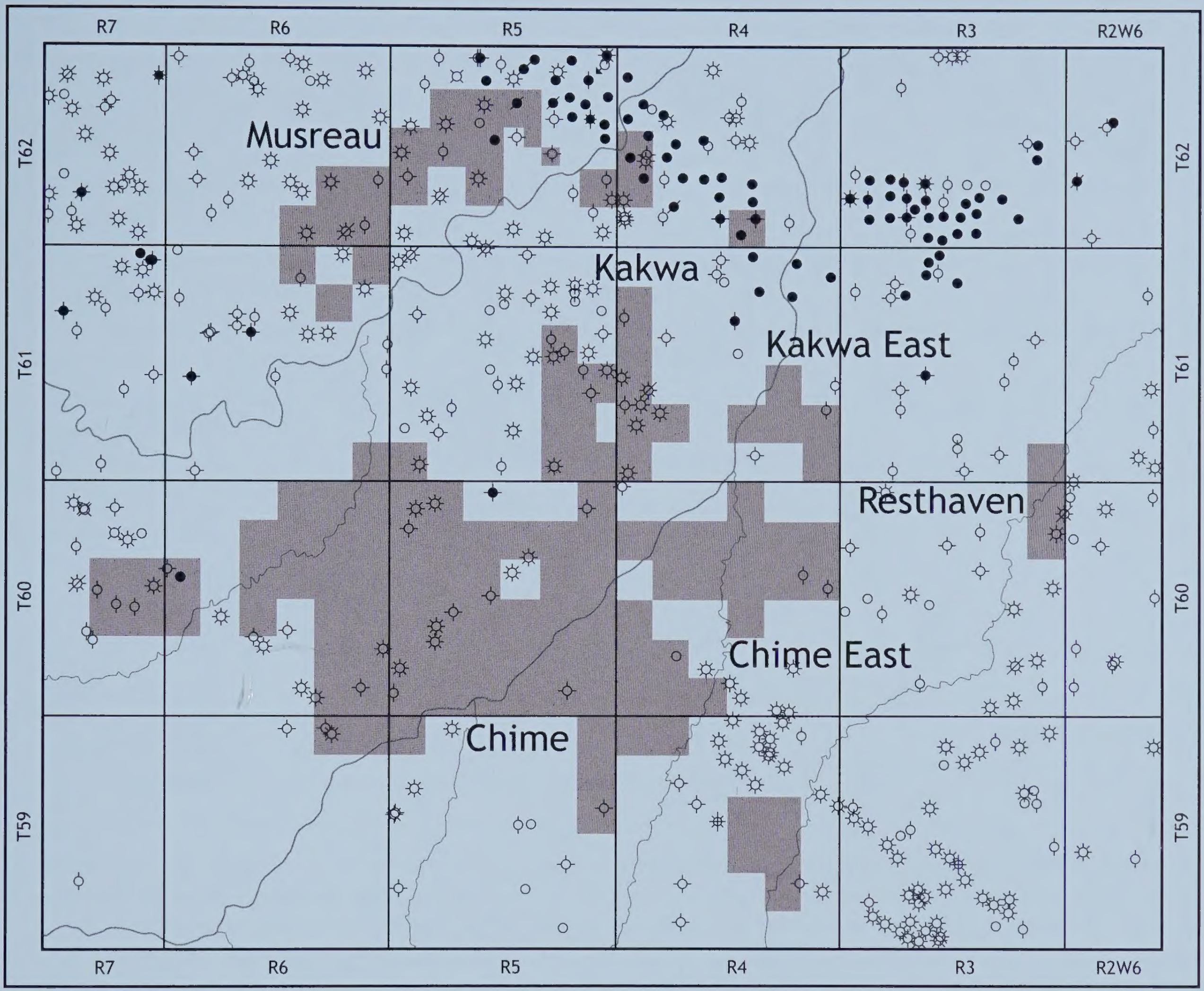
During 2006, the Company participated in three potential gas wells at MUSREAU. One well is to be completed in the first quarter of 2007, one well resulted in a gas well, and Cinch did not participate in the completion on the third well. Operators in the area have filed down-spacing applications which are expected to be approved in early 2007. The Company is planning to drill several down-spaced wells in the area along with re-completing additional prospective horizons in existing well bores.

At KAKWA, Cinch participated in drilling four wells in 2006, resulting in three gas wells and one abandoned well. These gas wells have all been completed and placed on production. Additional down spaced drilling is currently planned for 2007. In KAKWA NORTH, Cinch operated the re-entry of a well in 2006 which was completed as a gas well in the Cardium zone at a stabilized flow rate of 2 mmcfpd. This well has now been placed on production by the operator.

At RESTHAVEN, the Company participated, through farmout, in a significant dual zone gas discovery. The 9-25-60-3W6 well commenced production in November at 6.5 mmcfpd along with significant natural gas liquids from the Dunvegan zone. In February 2007, the operator shut in the Dunvegan zone and placed the Gething zone on

production at an initial rate of 7 mmcfpd, along with significant natural gas liquids. The operator will be commingling the Dunvegan and Gething zones once the Gething pressures have declined. Cinch is projecting a commingled rate of 3 mmcfpd for this well in 2007. Additional drilling opportunities exist on the Company's acreage once down spacing applications are approved.

ALBERTA AREAS OF EXPLORATION

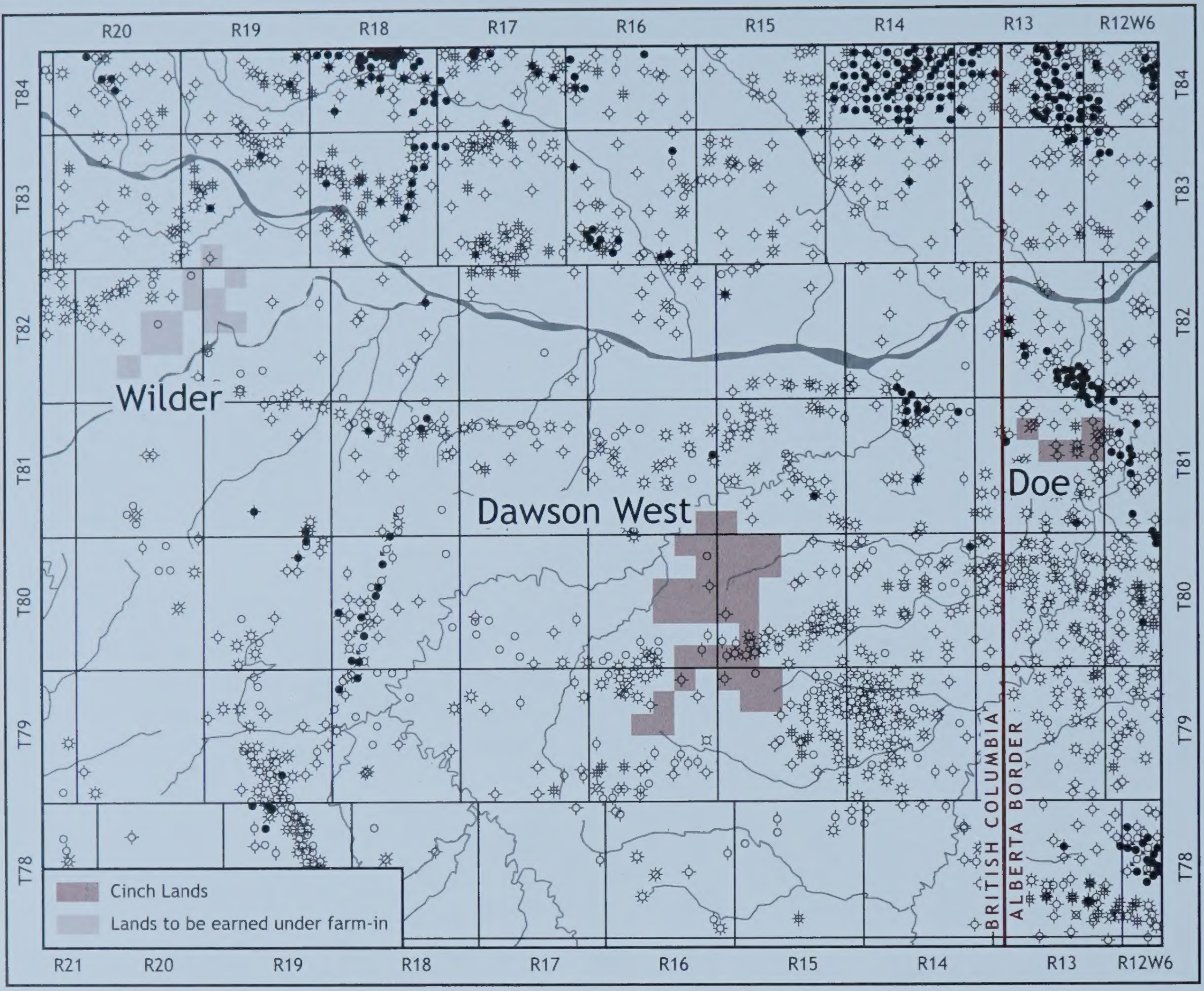


At CHIME EAST, Cinch operated the drilling of the 12-24-60-4W6 dual zone gas well. The Company is currently evaluating tie-in options for this well and additional drilling opportunities on the acreage for 2007.

In the KAKWA EAST area, the Company operated and completed an oil discovery at 15-12-61-4W6. This well is being evaluated for tie-in as the oil zone has associated natural gas production. Cinch has identified a number of development locations offsetting this discovery. The timing of these locations is dependent on access being granted by the Forestry department and economics of this project due to the associated natural gas production which must be conserved and tied-in.

Cinch is continuing to pursue and evaluate new projects and hence participated in two prospects located in the vicinity of the Company's DAWSON area. Cinch participated in the drilling of a Boundary Lake oil well at DOE which has extended the Doe Boundary Lake C Pool westward. The Company has earned interests ranging from 40-50% in 3,200 acres on this prospect. Additional drilling plans will depend on the productive rates from this oil well. At DAWSON, the Company acquired 3-D seismic which has identified a Kiskatinaw prospect. Drilling for this prospect is scheduled for mid 2007.

BRITISH COLUMBIA AREAS OF EXPLORATION



At WILDER British Columbia, the Company has committed to a new prospect for 2007, which requires Cinch to complete a cased potential gas well, and drill and complete a new well for a 50% working interest in 4 sections of land. The Company will have the option to drill a well to earn a 50% working interest in an additional 8 sections of land. This prospect has considerable scope, should it be successful, with crown lands available for acquisition. This prospect identifies with Cinch's strategy to acquire prospects which have considerable growth opportunities through drilling commitments.

Wells Drilled

	December 31, 2006		December 31, 2005	
	Gross	**Net**	Gross	Net
Natural gas	**11**	**3.2**	14	6.4
Oil	**2**	**0.9**	0	0
Dry and abandoned	**4**	**1.7**	2	1.3
Total	**17**	**5.8**	16	7.7

UNDEVELOPED LAND

Cinch's undeveloped land base of 120,367 gross acres (52,988 net acres) continues to represent a significant asset to the Company. Industry has continued to pay record land prices during 2006 for undeveloped lands, particularly in the Deep Basin fairway, which is the core area for Cinch. Based on an internal evaluation, Cinch places a value of approximately $15 million on its undeveloped lands.

The Company holds an average net working interest of 44% in its undeveloped land inventory, the majority of which is operated by Cinch. This land base allows the Company to continue with an active exploration program without having to compete with industry at high priced land sales and to farmout lands to obtain leverage.

Undeveloped Land Holdings

	December 31, 2006	December 31, 2005
Gross Acres	**120,367**	108,307
Net Acres	**52,988**	48.826
Average Working Interest	**44%**	45%

RESERVES

The corporate reserves estimates, effective December 31, 2006, were prepared by the independent engineering firm of GLJ Petroleum Consultants Ltd. ("GLJ") in accordance with the definitions set out under National Instrument 5l-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). The reserve highlights are:

- Total proven reserves at December 31, 2006 increased 18% to 3.9 million BOE compared to 3.3 million BOE at December 31, 2005.
- Total proven plus probable reserves at December 31, 2006 increased 21% to 5.8 million BOE compared to 4.8 million BOE at December 31, 2005.
- On a proven plus probable basis, the finding, development and acquisition costs were $25.53 per BOE ($34.92 per BOE on a proven basis).
- On a proven plus probable basis, the finding and development costs were $31.12 per BOE ($39.11 per BOE on a proven basis).

FORECASTED PRICES AND COSTS

Summary of Oil and Gas Reserves - Company Interest Reserves(1)

	Light and Medium Crude Oil (mbbls)	Natural Gas Liquids (mbbls)	Natural Gas (mmcf)	Total 2006 (mboe)	Total 2005 (mboe)	Variance 2006 vs 2005 (mboe)
Proved - Developed Producing	29	530	17,471	3,471	2,920	551
- Developed Non Producing	8	39	2,131	402	325	77
- Undeveloped	0	1	263	45	49	(4)
Total Proved	37	571	19,865	3,918	3,295	623
Probable	36	292	9,497	1,911	1,489	422
Total Proved Plus Probable	73	863	29,363	5,830	4,784	1,046

Note: May not add due to rounding

(1) "Company Interest" means the total working interest (operating and non-operating) share before deduction of royalties payable to others and including any royalty interest of Cinch.

Net Present Value of Reserves Before Income Taxes - Forecasted Prices and Costs

	Undiscounted	Discounted at			
	0%	8%	10%	15%	20%
December 31, 2006(1), (2),(3)	($M)	($M)	($M)	($M)	($M)
Proved - Developed Producing	101,932	64,659	59,606	50,263	43,826
- Developed Non-Producing	11,383	6,342	5,673	4,457	3,640
- Undeveloped	358	74	22	(84)	(164)
Total Proved	113,673	71,074	65,301	54,637	47,302
Probable	62,825	21,509	18,151	12,847	9,741
Total Proved Plus Probable	176,498	92,583	83,452	67,484	57,043

Note: May not add due to rounding

(1) Utilizing GLJ January 1, 2007 price forecast.

(2) As required by NI 51-101, undiscounted well abandonment costs of $1.7 million for total proved reserves and $2.1 million for total proved plus probable reserves are included in the Net Present Value determination. No allowance was made for reclamation of well sites or for the abandonment and reclamation of any facilities.

(3) Prior to provision of income taxes, interest, debt service charges and general and administrative expenses. It should not be assumed that the undiscounted and discounted future net revenues estimated by GLJ represent the fair market value of the reserves.

Pricing Assumptions - Forecasted Prices and Costs

The January 1, 2007 pricing forecasts presented below have been prepared by GLJ. These prices have been utilized in determining the reserves and cash flow forecasts above.

Year	Oil Edmonton Par Price 40° API ($CDN/Bbl)	Natural Gas Alberta Plant Gate ($CDN/MMBtu)	Propane Edmonton ($CDN/Bbl)	Butane Edmonton ($CDN/Bbl)	Pentanes Plus Edmonton Light ($CDN/Bbl)
2007	70.25	7.00	45.00	56.25	71.75
2008	68.00	7.25	43.50	50.25	69.25
2009	65.75	7.55	42.00	48.75	67.00
2010	64.50	7.60	41.25	47.75	65.75
2011	64.50	7.65	41.25	47.75	65.75
2012	65.00	7.95	41.50	48.00	66.25
2013	66.25	8.10	42.50	49.00	67.50
2014	67.75	8.30	43.25	50.25	69.00
2015	69.00	8.50	44.25	51.00	70.50
2016	70.50	8.65	45.00	52.25	72.00
2017	71.75	8.85	46.00	53.00	73.25
2018	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

CONSTANT PRICES AND COSTS

Net Present Value of Reserves Before Income Taxes - Constant Prices and Costs

	Undiscounted	Discounted at:			
December 31, 2006(1), (2), (3)	0% ($M)	8% ($M)	10% ($M)	15% ($M)	20% ($M)
Proved - Developed Producing	73,523	50,086	46,613	39,980	35,245
- Developed Non-Producing	7,649	4,522	4,072	3,229	2,645
- Undeveloped	16	(183)	(219)	(294)	(350)
Total Proved	81,188	54,425	50,466	42,916	37,540
Probable	36,335	14,964	12,862	9,326	7,119
Total Proved Plus Probable	117,523	69,389	63,328	52,242	44,658

Note: May not add due to rounding

(1) Price assumptions: $67.58/Bbl Cdn Edmonton Light Sweet Crude, $71.55/bbl Cdn. Edmonton Pentanes Plus and $5.87/mmbtu Cdn. Alberta Plant Gate - Spot.

(2) As required by NI 51-101, undiscounted well abandonment costs of $1.2 million for total proved reserves and $1.3 million for total proved plus probable reserves are included in the Net Present Value determination. No allowance was made for reclamation of well sites or for the abandonment and reclamation of any facilities.

(3) Prior to provision of income taxes, interest, debt service charges and general and administrative expenses. It should not be assumed that the undiscounted and discounted future net revenues estimated by GLJ represent the fair market value of the reserves.

RESERVE RECONCILIATION

Reconciliation of Company Interest Reserves [1] by Principal Product Type - Forecast Prices and Costs

	Light and Medium Oil		Natural Gas Liquids		Associated and Non-Associated Gas		Equivalence	
	Proved (mbbls)	Total Proved Plus Probable (mbbls)	Proved (mbbls)	Total Proved Plus Probable (mbbls)	Proved (mmcf)	Total Proved Plus Probable (mmcf)	Proved (mboe)	Total Proved Plus Probable (mboe)
December 31, 2005	67.5	95.6	565.5	823.2	15,971.6	23,192.2	3,294.9	4,784.2
Technical	(54.9)	(81.0)	(48.2)	(63.5)	732.5	417.2	19.0	(74.9)
Discoveries	0.0	0.0	20.3	24.4	494.8	593.8	102.8	123.4
Drilling Extensions	25.5	59.9	26.2	36.2	1,668.2	2,488.2	329.7	510.8
Infill Drilling	0.0	0.0	50.7	70.4	1,447.4	1,993.0	292.0	402.6
Improved Recovery	0.0	0.0	0.0	0.0	0	0	0	0
Acquisition	0.0	0	30.4	46.3	1,686.7	2,814.2	311.5	515.3
Production	(1.3)	(1.3)	(74.2)	(74.2)	(2,135.7)	(2,135.7)	(431.5)	(431.5)
December 31, 2006	36.8	73.2	570.7	862.8	19,865.5	29,362.8	3,918.4	5,829.8

Note: May not add due to rounding

(1) Company interest reserves means the total working interest (operating and non-operating) share before deduction of royalties payable to others and including royalty interests of Cinch.

Reconciliation of Company Net Reserves[1] By Principal Product Type - Forecast Prices and Costs

	Light and Medium Oil			Associated and Non-Associated Gas			Natural Gas Liquids		
FACTORS	Net Proved (mbbls)	Net Probable (mbbls)	Net Proved Plus Probable (mbbls)	Net Proved (mmcf)	Net Probable (mmcf)	Net Proved Plus Probable (mmcf)	Net Proved (mbbls)	Net Probable (mbbls)	Net Proved Plus Probable (mbbls)
December 31, 2005	55	23	78	12,019	5,262	17,281	366	163	529
Drilling Extensions	23	29	52	1,224	584	1,807	17	6	23
Infill Drilling	0	0	0	1,074	411	1,486	34	13	47
Improved Recovery	0	0	0	0	0	0	0	0	0
Technical Revisions	(43)	(21)	(64)	378	(244)	134	(24)	(11)	(35)
Discoveries	0	0	0	441	84	525	15	3	17
Acquisitions	0	0	0	1,196	808	2,004	16	9	25
Dispositions	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0
Production	(1)	0	(1)	(1,516)	0	(1,516)	(56)	0	(56)
December 31, 2006	34	31	65	14,815	6,906	21,721	368	183	551

Note: May not add due to rounding

(1) Net reserves means the Company's interest (operating and non-operating) share after deduction of royalty obligations, plus the Company's royalty interest in production or reserves.

Finding and Development Costs (F&D) and Finding, Development and Net Acquisition Costs (FD&A)

NI 51-101 specifies how finding and development ("F&D") costs should be calculated if they are reported. Essentially NI 51-101 requires that the exploration and development costs incurred in the year along with the change in estimated future development costs be aggregated and then divided by the applicable reserve additions. The calculation specifically excludes the effects of acquisitions and dispositions on both reserve and costs. By excluding the effects of acquisitions and dispositions Cinch believes that the provisions of NI 51-101 do not fully reflect Cinch's ongoing reserve replacement costs. Since acquisitions can have a significant impact on Cinch's annual reserve replacement costs, to not include these amounts could result in an inaccurate portrayal of Cinch's cost structure. Accordingly, Cinch will also report finding, development and acquisition ("F,D&A") costs that will incorporate all acquisitions net of any dispositions during the year.

	2006		2005		3 year average	
	Proved	Proved Plus Probable	Proved	Proved Plus Probable	Proved	Proved Plus Probable
Capital ($'000s)						
Exploration and development (1)	**29,058**	**29,058**	36,045	36,045	27,051	2,7051
Acquisition capital	**7,779**	**7,779**	1,515	1,515	19,646	19,646
Change in future capital	**23**	**874**	1,796	5,638	915	2,479
Total capital including change in future capital	**36,860**	**37,711**	39,356	43,198	47,612	49,177
Total capital excluding goodwill	**36,860**	**37,711**	39,356	43,198	42,740	44,305
Reserve additions (mboe) (2)						
Exploration and development	**744**	**962**	715	1,201	910	1,222
Acquisition	**312**	**515**	187	259	614	861
Total reserve additions (mboe) (2)	**1,056**	**1,477**	902	1,460	1,523	2,083
Costs ($/boe)						
F&D	**39.11**	**31.12**	52.92	34.71	30.75	24.17
FD&A	**34.92**	**25.53**	43.63	29.59	31.26	23.60
FD&A excluding goodwill	**34.92**	**25.53**	43.63	29.59	28.06	21.27

Note: May not add due to rounding

(1) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

(2) Company interest, meaning the total working interest (operating and non-operating) share before deduction of royalties payable to others and including any royalty interest of Cinch.

NET ASSET VALUE

($ million, except per share amounts)	Forecasted Prices 8% B.T.
Reserves, proven and probable (1)	92.6
Seismic data	2.0
Undeveloped land (2)	15.0
Working capital	(23.7)
Common shares outstanding, basic	47.8
Net asset value ($/share)	1.80

(1) Net present value of future net revenues before income taxes.

(2) In our calculation, we have used approximately $283 per acre as the average land price for our undeveloped land (52,988 net acres).

Production & Reserve Life Index

The Company's reserve life index using annualized fourth quarter production is 8.1 years for proven BOE reserves compared to 7.3 years in 2005 and 12.1 years for proven plus probable BOE reserves compared to 10.5 years in 2005.

	2006		2005	
Production rate is an:	**Annualized Q4**	**Average**	Annualized Q4	Average
Production (boe/d)	**1,320**	**1,182**	1,245	1,297
Proved reserves (mboe) (1)	**3,918**	**3,918**	3,295	3,295
Proved reserve life index (years)	**8.1**	**9.1**	7.3	7.0
Proved plus probable reserves (mboe) (1)	**5,830**	**5,830**	4,784	4,784
Proved plus probable reserve life index (years)	**12.1**	**13.5**	10.5	10.1

(1) Company interest reserves means the total working interest (operating and non-operating) share before deduction of royalties payable to others and including royalty interests of Cinch.

Cinch exited the year at approximately 1,600 BOED.

Reserve Replacement

The Company's 2006 capital investment program replaced 2006 average production by a factor of 2.4 times on a proved basis and 3.4 times on a proved plus probable basis.

	2006		2005	
Production total is an:	**Annualized Q4**	**Average**	Annualized Q4	Average
Production (mboe)	**481.7**	**431.4**	454.3	473.4
Proved reserve additions after revisions of prior periods (mboe) (1)	**1,056**	**1,056**	902	902
Proven replacement ratio	**2.2**	**2.4**	2	1.9
Proved plus probable reserve additions after revision of prior periods (mboe) (1)	**1,477**	**1,477**	1,460	1,460
Proved plus probable replacement ratio	**3.1**	**3.4**	3.2	3.1

(1) Company interest reserves means the total working interest (operating and non-operating) share before deduction of royalties payable to others and including royalty interests of Cinch.

Recycle Ratio

The recycle ratio is a measure for evaluating the effectiveness of a company's re-investment program. The ratio measures the efficiency of capital investment. It accomplishes this by comparing the operating netback per barrel of oil equivalent to that year's reserve finding and development costs. Cinch Energy presents the recycle ratio on both an FD&A basis (based on 2006 actual FD&A) and an F&D basis.

	2006		2005	
	FD&A	**F&D**	FD&A	F&D
Operating netbacks ($/BOE)	**30.20**	**30.20**	36.92	36.92
Proved finding, development and net acquisition costs after revision of prior periods and including the change in future development capital ($/BOE)	**34.92**	**39.11**	43.63	52.92
Proved recycle ratio	**0.9**	**0.8**	0.9	0.7
Proved plus probable finding, development and acquisition costs after revisions of prior periods and including the change in future development capital ($/BOE)	**25.53**	**31.12**	29.59	34.70
Proved plus probable recycle ratio	**1.2**	**1.0**	1.2	1.1

Note: May not add due to rounding

Management's Discussion and Analysis

Sarah Tait, Controller

March 7, 2007

The following management's discussion and analysis ("MD&A") should be read in conjunction with Cinch Energy Corp.'s ("Cinch" or the "Company") audited financial statements for the years ended December 31, 2006 and 2005. This commentary is based on the information available as at, and is dated, March 7, 2007. Additional information relating to Cinch, including Cinch's Annual Information Form when filed, is on SEDAR at www.sedar.com.

Forward Looking Statements

Statements throughout this MD&A that are not historical facts may be considered to be "forward looking statements". These forward looking statements sometimes include words to the effect that management believes or expects a stated condition or result. All estimates and statements that describe the Company's objectives, goals, or future plans, including management's assessment of future plans and operations, anticipated commodity prices, production estimates and expected production rates and declines, timing of bringing on additional production, partner risk, and the effect of delays in drilling, completing and tieing-in wells and the effects of infrastructure issues, expected royalty rates and expenses related thereto, general and administrative expenses and other expenses, effects of the results of successful wells, level of capital expenditures and the method of funding of capital expenditures, and the expected levels of activities may constitute forward-looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, volatility of commodity prices, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to complete and/or realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and changes in the regulatory and taxation environment. As a consequence, the Company's actual results may differ materially from those expressed in, or implied by, the forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included elsewhere herein and in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), or at the Company's website (www.cinchenergy.com). Furthermore, the forward-looking statements contained in this MD&A are made as at the date of this MD&A and the Company does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Non-GAAP Measures

The MD&A contains the term "funds from operations" which should not be considered an alternative to, or more meaningful than, cash provided by operating activities or net income as determined in accordance with Canadian generally accepted accounting principles ("GAAP") as an indicator of the Company's performance. The Company considers funds from operations to be a key measure that demonstrates its ability to generate funds for future growth through capital investment. Funds from operations is calculated by taking cash provided by operating activities on the statement of cash flows less the effect of changes in non-cash working capital related to operating activities. The Company's determination of funds from operations may not be comparable with the calculation of similar measures by other companies. The Company also presents funds from operations per share, where funds from operations is divided by the weighted average number of shares outstanding to determine per share amounts. The Company evaluates its performance based on earnings and funds from operations.

The MD&A contains the term "net debt" which is the sum of the working capital (deficiency) and the outstanding credit facility balance. This number may not be comparable to that reported by other companies.

Barrel of Oil Equivalency

Natural gas volumes are converted to barrels of oil equivalent (BOE) on the basis of six thousand cubic feet (mcf) of gas to one barrel (bbl) of oil. The term "barrels of oil equivalent" may be misleading, particularly if used in isolation. A BOE conversion ratio of six mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Operational Update

The Company's program for the fourth quarter of 2006 consisted primarily of completing and tieing-in wells drilled in the third quarter of 2006 in the Kakwa, Kakwa North and Chime areas.

Production levels increased in the fourth quarter of 2006 compared to the prior three quarters of 2006 due to the Resthaven 9-25 well, which came on production at rates of approximately 200 BOE/d net to Cinch at the end of November, 2006, after having previously been shut-in on September 30, 2006 for testing. The Kakwa North 10-20 well also came on production in the fourth quarter of 2006, as did the Bigstone 3-25 well. In addition, a well in the Kakwa area and a well in the Chime area were tied-in and commenced production in the last two weeks of December.

As noted above, the Bigstone 3-25 well, the most significant well in our Bigstone area, was brought back on production in December of 2006 at production rates of approximately 115 BOE/d net to Cinch. This well was shut in again on January 30, 2007 and we anticipate that production from Bigstone will be sporadic until April of 2007 due to plant capacity issues.

Production

	Three Months Ended December 31,			Year Ended December 31,		
	2006	2005	Change	**2006**	2005	Change
Sales volumes			%			%
Natural gas (Mcf/d)	**6,500**	6,248	4	**5,851**	6,478	(10)
Liquids (Bbl/d)	**236**	203	16	**207**	217	(5)
Equivalence (BOE/d)	**1,320**	1,245	6	**1,182**	1,297	(9)
Sales prices	$	$	%	$	$	%
Natural gas ($/Mcf)	**7.49**	12.44	(40)	**7.14**	9.59	(26)
Liquids($/Bbl)	**57.56**	62.69	(8)	**64.53**	59.83	8
Equivalence ($/BOE)	**47.22**	72.68	(35)	**46.62**	57.90	(19)

Sales volumes for the year ended December 31, 2006 decreased compared to 2005 due to declines in production from wells that came on in late 2004 and produced at higher rates in 2005.

Sales volumes for the three months ended December 31, 2006 increased compared to the same period of 2005 due to an increased number of producing wells, with the most significant well being the Resthaven 9-25 well. This well commenced production on November 25 at rates of approximately 200 BOE/d (net). The Kakwa North 10-20 well also came on production late in November 2006 at rates of approximately 90 BOE/d (net). There were also two new wells, one each in Chime and Kakwa, which came on production late in December 2006 and as a result the Company exited 2006 at a rate of approximately 1600 BOE/d. It is anticipated that the new production will experience typical Deep Basin decline rates in their first year of production.

The Company's production is primarily from deep, tight gas, which normally experiences high decline rates in the first year, with decline rates typically reducing and stabilizing thereafter and providing a strong production base. As the Company builds a larger production base, declines on new production should have a less significant impact.

The Company's production volumes in 2006 have been impacted by plant capacity issues. The Bigstone production was completely shut-in for the second and third quarter of 2006, coming back on production late in the fourth quarter of 2006. The Musreau plant had also experienced capacity issues throughout the first three quarters, causing wells to be sporadically shut in.

Natural gas prices dropped 40% in the fourth quarter of 2006 compared to the same quarter of 2005 and 26% year over year. The Company's natural gas production continues to be unhedged and is marketed in the Alberta spot market.

Natural gas liquids pricing has dropped 8% in the fourth quarter of 2006 compared to the same quarter of 2005 and 17% since the third quarter of 2006. The natural gas liquids pricing for the year ended December 31, 2006 has increased 8% over 2005. Natural gas liquids represent approximately 24% of oil and gas revenues. The Company has not hedged any of its liquids production.

Revenues

Dollars in thousands, except per unit amounts

	Three Months Ended December 31,			Year Ended December 31,		
	2006	2005	Change	**2006**	2005	Change
	$	$	%	**$**	$	%
Oil and gas sales, net of transportation	**5,733**	8,323	(31)	**20,112**	27,413	(27)
Per BOE	**47.22**	72.68	(35)	**46.62**	57.90	(19)

Revenues for the three months and year ended December 31, 2006 are lower than the same periods of 2005 primarily as a result of lower natural gas prices, as previously discussed.

Royalties

Dollars in thousands, except per unit amounts

	Three Months Ended December 31,			Year Ended December 31,		
	2006	2005	Change	**2006**	2005	Change
	$	$	%	**$**	$	%
Royalties, net of ARTC	**1,126**	2,109	(47)	**4,111**	7,213	(43)
Per BOE	**9.27**	18.42	(50)	**9.53**	15.23	(37)

Royalty expense, net of Alberta Royalty Tax Credit ("ARTC"), decreased in the three months and year ended December 31, 2006 compared to the same periods of 2005 as a result of lower commodity prices. Two higher producing wells also paid out in the second and third quarters of 2005; hence the Company did not pay gross overriding royalties on these wells in 2006. The Company's royalty rate (royalties net of ARTC as a percentage of oil and gas sales) was lower in 2006 at 20% versus 26% in 2005. Some of the Company's higher producing wells which came on production in 2006 are eligible for royalty holiday thereby reducing the royalty rate when compared to total oil and gas sales. There was also approximately $600 thousand more in gas cost allowance recorded in 2006 compared to 2005, thereby further reducing the royalty rate. The increase in royalty expense from the third quarter of 2006 can be attributed to increased volumes as well as increased natural gas prices.

The Company anticipates that its royalty rate in 2007 will be higher than that of 2006, due to the exhaustion of certain royalty holidays and due to the elimination of ARTC effective January 1, 2007, previously an annual benefit to the Company of $500 thousand. Anticipated royalty rates can change, depending upon commodity prices, actual success achieved and the zone in which productive success is achieved.

Operating Expenses

Dollars in thousands, except per unit amounts

	Three Months Ended December 31,			Year Ended December 31,		
	2006	2005	Change	**2006**	2005	Change
	$	$	%	**$**	$	%
Operating	**759**	633	20	**3,065**	2,722	13
Per BOE	**6.25**	5.53	13	**7.10**	5.75	23

Total operating expenses, as well as operating expenses per BOE, increased in the three months and year ended December 31, 2006 compared to the same periods of 2005, due to increased expenses relating to an additional 10 producing wells, as well as other increased operating expenses.

For the year ended December 31, 2006, the increases related primarily to compressor costs ($50 thousand), methanol costs ($50 thousand), contractor costs associated with the increased activity ($120 thousand) as well as increased property taxes ($45 thousand). Gas gathering and processing fees are also approximately $60 thousand or $0.42/BOE higher for the year ended December 31, 2006 compared to the same period of 2005.

Total operating expenses as well as operating expenses per BOE were lower in the fourth quarter of 2006 compared to the third quarter of 2006 primarily due to property taxes expensed in the third quarter, partially offset by increased gas gathering and processing fees in the fourth quarter attributable to higher production.

Operating expenses are expected to average approximately $6.50 per BOE in 2007.

General and Administrative Expenses

Dollars in thousands, except per unit amounts

	Three Months Ended December 31,			Year Ended December 31,		
	2006	2005	Change	**2006**	2005	Change
	$	$	%	**$**	$	%
General and administrative	**932**	912	2	**3,548**	2,749	29
Per BOE	**7.68**	7.96	(4)	**8.22**	5.81	41

Total general and administrative expenses increased for the three months and year ended December 31, 2006 compared to the same periods of 2005 due to the hiring of additional employees and the increased use of contractors and consultants to handle operation, administration and exploration activities. The Company does not capitalize any general and administrative expenses. Due to the increased number of employees and the need to remain competitive in the marketplace, salaries and related compensation increased approximately $600 thousand for the year ended December 31, 2006. This amount includes the increase in non-cash stock based compensation expense of $240 thousand attributable to a greater number of stock options outstanding (4,071,334 options at December 31, 2006 compared to 2,328,000 options at December 31, 2005). As at March 7, 2007, the Company has 4,078,000 options outstanding, amounting to approximately 7.3% of outstanding common shares and special warrants. Public company related expenses such as annual reports, corporate governance compliance, audit fees, and reserve reports have also increased approximately $130 thousand for the year ended December 31, 2006 compared to the same period of 2005. Insurance costs have also increased $60 thousand over the past year with increases consistent throughout the industry.

General and administrative expenses per BOE have decreased in the fourth quarter of 2006 compared to the same period as 2005 due to increased production in the fourth quarter of 2006. The general and administrative expenses per BOE for the year ended December 31, 2006 have increased over 2005 primarily due to higher expenses.

Total general and administrative expenses increased in the fourth quarter of 2006 compared to the third quarter due to increased compensation expense, including $60 thousand in non-cash stock based compensation expense, as well as increased public company related expenses, primarily relating to corporate governance compliance.

Cash general and administrative expenses per BOE for 2006 were lower than the forecasted $6.50/BOE at approximately $6.22 per BOE. The non-cash stock based compensation expense averaged approximately $2.00 per BOE for all of 2006, as anticipated.

Cash general and administrative expenses for 2007 are expected to average approximately $5.50 per BOE as a result of forecasted higher production volumes for the full year. The non-cash stock based compensation expense is expected to average $2.00 per BOE for 2007.

Interest Expense

Dollars in thousands, except per unit amounts

	Three Months Ended December 31,			Year Ended December 31,		
	2006	2005	Change	**2006**	2005	Change
	$	$	%	**$**	$	%
Interest expense	**250**	6	4,067	**461**	299	54
Per BOE	**2.06**	0.05	4,020	**1.07**	0.63	70

Interest expense increased in the three months and year ended December 31, 2006 compared to the same periods of 2005 due to higher draws on the Company's bank credit facility in 2006. The Company did not draw on its $33 million bank line until the second quarter of 2006 and exited the year with an amount outstanding under its credit facility of $17.3 million.

Accretion of Asset Retirement Obligations Expense

Dollars in thousands, except per unit amounts

	Three Months Ended December 31,			Year Ended December 31,		
	2006	2005	Change	**2006**	2005	Change
	$	$	%	**$**	$	%
Accretion expense	**14**	45	(69)	**63**	158	(60)
Per BOE	**0.12**	0.40	(70)	**0.15**	0.33	(55)

Accretion expense decreased in the three months and year ended December 31, 2006 compared to the same periods of 2005 as a result of an extension of the abandonment dates of the wells based on evaluations completed in 2006, in large part due to the pricing used in the reserves report extending the economic life of the wells. The economic lives of the wells were assessed and determined to be longer than originally estimated and as such the liability is being accrued over a longer period of time. The decrease is partially offset by the accretion recorded associated with new wells completed during the year.

Depletion and Depreciation Expense

Dollars in thousands, except per unit amounts

	Three Months Ended December 31,			Year Ended December 31,		
	2006	2005	Change	**2006**	2005	Change
	$	$	%	**$**	$	%
Depletion and depreciation	**3,243**	2,697	20	**10,897**	9,257	18
Per BOE	**26.71**	23.55	13	**25.26**	19.55	29

Total depletion and depreciation expense as well as depletion per BOE for the three months and year ended December 31, 2006 increased compared to the same periods of 2005 due to a larger capital asset balance being depleted, partially offset by reserve additions in 2006. The Company has experienced overall higher capital costs in 2006.

Taxes

Dollars in thousands, except per unit amounts

	Three months ended December 31,			Year ended December 31,		
	2006	2005	Change	**2006**	2005	Change
	$	$	%	**$**	$	%
Current	**–**	18	(100)	**–**	98	(100)
Future income taxes (recovery)	**(81)**	637	(113)	**(1,570)**	1,710	(192)
Per BOE	**(0.66)**	5.72	(112)	**(3.64)**	3.82	(195)

Current taxes were reduced to nil in the second quarter of 2006 to reflect the elimination of large corporations tax effective January 1, 2006, which became law on June 22, 2006.

The future income tax recovery for the three months ended December 31, 2006 is consistent with the net loss experienced during the quarter.

The future income tax recovery recorded for the year ended December 31, 2006 reflects the reduction in future tax rates as legislated by the federal government on June 22, 2006. In the second quarter of 2006, the future tax liability previously recognized by the Company was recalculated to reflect these lower rates, and the difference between the original estimate of the future tax liability and the June 30, 2006 estimate at lower tax rates resulted in a large future tax recovery recorded in the second quarter.

Tax pools at December 31, 2006:

Dollars in thousands

	2006	2005
	$	$
COGPE	**12,593**	7,620
CDE	**23,266**	18,412
CEE	**18,272**	15,723
UCC	**21,346**	15,488
	75,477	57,243

The Company's tax pools increased significantly in 2006 as a result of capital expenditures which were higher than the tax deductions needed to eliminate taxable income. An equity financing completed in 2005 included flow through common shares of $10 million, for which the renunciation was completed in 2006 and deducted from the above tax pools.

Net Income and Funds from Operations

In thousands, except per share figures

	Three Months Ended December 31,			Year Ended December 31,		
	2006	2005	Change	**2006**	2005	Change
	$	$	%	**$**	$	%
Net income	**(488)**	1,364	(136)	**(317)**	3,364	(109)
per basic share	**(0.01)**	0.03	(133)	**(0.01)**	0.08	(113)
per diluted share	**(0.01)**	0.03	(133)	**(0.01)**	0.08	(113)
Funds from operations	**2,970**	4,899	(39)	**9,966**	15,042	(34)
per basic share	**0.06**	0.10	(40)	**0.21**	0.38	(44)
per diluted share	**0.06**	0.10	(40)	**0.20**	0.36	(44)
Weighted average shares & special warrants outstanding	**47,813**	47,813	–	**47,813**	40,047	19

For the year ended December 31, 2006, the Company incurred a net loss, attributable to lower natural gas pricing as well as higher general and administrative costs, higher operating costs, as well as higher depletion expense compared to the same period of 2005. The Company incurred a net loss for the three months ended December 31, 2006, a decrease compared to the same period of 2005 due to the same factors as discussed above. In 2006, the Company was largely affected by the decline in commodity prices and anticipates further volatility in commodity prices in 2007.

The Company generated positive funds from operations for the three months and year ended December 31, 2006 but compared to the same periods of 2005 funds from operations are lower primarily due to significantly lower natural gas prices.

Liquidity and Capital Resources

Dollars in thousands

		As at December 31,	
	2006	2005	Change
	$	$	%
Working capital (deficiency), excluding credit facility	**(6,441)**	3,490	(285)
Credit facility	**(17,304)**	_	(100)
Working capital (net debt)	**(23,745)**	3,490	(780)
Capital lease obligation	**(277)**	(421)	(34)
Shareholders' equity	**(90,066)**	(93,400)	(4)

At December 31, 2006, the Company had net debt of $23.7 million, including a working capital deficiency of $6.4 million, primarily as a result of $37 million in capital expenditures incurred in 2006. The Company did not complete any financings in 2006 and funded its expenditures with cash flow and net debt. Subsequent to December 31, 2006, the Company issued 7,812,500 common shares on a flow through basis at a price of $1.28 per share for gross proceeds of $10,000,000.

The fourth quarter funds from operations increased by $900 thousand from the third quarter of 2006 and, combined with capital expenditures of $9.3 million in the fourth quarter, resulted in the Company exiting 2006 with net debt of $23.7 million. Net debt was slightly lower than anticipated by the Company as a result of stronger than forecast natural gas prices in the fourth quarter and the resultant improvement in funds from operations.

Management intends to fund its 2007 capital program with a combination of funds generated from operations, funds received from the financing of flow through shares noted above, and its bank credit facility.

The decrease in shareholder's equity at December 31, 2006 from December 31, 2005 is due to the tax effect of $10 million in flow through share expenditures renounced in the first quarter of 2006, effective December 31, 2005.

Capital Expenditures

Additions to property, plant and equipment

Dollars in thousands

	Year Ended December 31,	
	2006	2005
	$	$
Land and rentals	**6,462**	4,083
Seismic	**984**	796
Drilling, completing and equipping	**23,989**	26,046
Pipelines and facilities	**5,378**	5,038
Other assets	**153**	82
Total	**36,966**	36,045

Capital expenditures for the year ended December 31, 2006 were incurred primarily on drilling, completing and tieing in locations in the Chime, Kakwa, and Musreau areas. In addition, the Company purchased land in 2006, focusing on the Kakwa, Chime and Dawson West areas, further increasing the Company's land base in its core areas as well as providing opportunities for further plays in the Dawson West area, which has become increasingly active.

Capital expenditures for 2006 include the April 2006 acquisitions of additional working interests in 7 producing gas wells as well as undeveloped land in the Chime area for a total of $10.75 million. The undeveloped land from these acquisitions was subsequently sold to a joint venture partner for $3 million, thereby reducing the Company's acquisition costs for the production and reserves to $7.75 million (net), which is included in the above total.

Management's primary strategy is to expend capital on exploration and development drilling and earn land by drilling. The Company may, however, also purchase land where considered strategic.

The Company's 2007 first quarter capital program will be focused on drilling, completing and tie-ing locations in the Chime, Chime East, Doe and Kakwa East areas.

Business Risks and Risk Management

The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Cinch attempts to reduce risk in accomplishing these goals through the combination of hiring experienced and knowledgeable personnel and careful evaluation.

The Company's program is exploratory in nature and in areas with deep, tight gas. The wells the Company drills therefore tend to be deep (a substantial portion are deeper than 2,500 meters), and are subject to higher drilling costs than those in more shallow areas. In addition, most wells require fracture treatment before they are capable of production, also increasing costs. The Company mitigates the additional economic pressure that this creates by carefully evaluating risk/reward scenarios for each location, by taking what management considers to be appropriate working interests after considering project risk, by practicing prudent operations so that drilling risk is decreased, by ranking and limiting the zones that the Company is willing to complete, and also by drilling deep so that the multi-zone potential of the area can be accessed and potentially developed. The Company operates the majority of its lands which provides a measure of control over the timing and location of capital expenditures. In addition, the Company monitors capital spending on an ongoing and regular basis so that the Company maintains liquidity and so that future financial resource requirements can be anticipated.

The financial capability of the Company's partners can pose a risk to the Company, particularly during periods when access to capital is more challenging and prices are depressed. The Company mitigates the risk of collection by attempting to obtain the partner's share of capital expenditures in advance of a project and by monitoring receivables regularly. The ability of the Company to implement its capital program when the financial wherewithal of a partner is challenged can be more difficult, although the Company attempts to mitigate the risk by cultivating multiple business relationships and obtaining new partners when needed and where possible.

Commodity price fluctuations can pose a risk to the Company, and management monitors these on an ongoing basis. External factors beyond the Company's control may affect the marketability of the natural gas and natural gas liquids produced. The Company has not, to date, implemented any hedging instruments.

The Company has selected the appropriate personnel to monitor operations and has automated field information where possible, so that difficulties and operational issues can be assessed and dealt with on a timely basis, and so that production can be maximized as much as possible. Not all operations issues, however, are within the Company's control. Management will address them nonetheless, and attempt to implement solutions, which may be by their nature longer term.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, and spills, each of which could result in damage to wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, the Company insures against most of these risks (although not all such risks are insurable). The Company maintains liability insurance in an amount that it considers consistent with industry practice, although the nature of these risks is such that liabilities could potentially exceed policy limits. The Company also reduces risk by operating a large percentage of its operations. As such, the Company has control over the quality of work performed and the personnel involved.

The Company anticipates making substantial capital expenditures in future for the exploration, development, acquisition and production of oil and natural gas reserves. If the Company's revenues or reserves decline, it may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing will be available. The Company mitigates this risk by monitoring expenditures, operations and results of operations in order to manage available capital effectively.

Attracting and retaining qualified individuals is crucial to the Company's success. The Company understands the importance of maintaining competitive compensation levels given this increasingly competitive environment in which the Company operates. The inability to attract and retain key employees could have a material adverse effect on the Company.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. In 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"), which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Company. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on the Company and its operations and financial condition.

The Company's ability to move heavy equipment in the field is dependent on weather conditions. Rain and snow can impact conditions, and many secondary roads and future oil and gas production sites are incapable of supporting the weight of heavy equipment until the roads are thoroughly dry. The duration of difficult conditions has a direct impact on the Company's activity levels and as a result can delay operations.

Disclosure Controls and Procedures

The Company has designed disclosure controls and procedures to provide reasonable assurance that material information relating to the Company required to be disclosed is recorded, processed, summarized and reported within the time periods specified by securities regulations and that information required to be disclosed is communicated to management on a timely basis. The Chief Executive Officer and the Chief Financial Officer have evaluated the effectiveness of these disclosure controls and procedures as of the end of the period covered by the annual filings and have concluded, based on such evaluation, that the Company's disclosure controls and procedures as of the end of such period are effective to provide reasonable assurance that material information relating to the Company is made known to them by others within the Company, particularly during the period in which the annual filings are being prepared.

Internal Controls over Financial Reporting

The Company's Chief Executive Officer and Chief Financial Officer have designed or caused to be designed under their supervision, internal controls over financial reporting relating to the Company to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

The Company's Chief Executive Officer and Chief Financial Officer are required to cause the Company to disclose any change in the Company's internal controls over financial reporting that occurred during the Company's most recent interim period that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during the three months ended December 31, 2006, that have materially affected, or are reasonably likely to affect, the Company's internal controls over financial reporting.

Future Prospects

Management continues to be optimistic about the growth of the Company, despite some challenges encountered in 2006. Cinch has expanded its land base in British Columbia, a new prospect for the Company. With prudent risk management, careful evaluation of results, continued development of the lands as well as expansion into new and existing areas, management believes that the Company will continue to be successful.

Contractual Obligations, Commitments, and Guarantees

The Company has contractual obligations and commitments in the normal course of its operating and financing activities. These obligations and commitments have been considered when assessing the Company's cash requirements in its analysis of future liquidity.

			Payments		
	Total	< 1 year	1-3 years	4-5 years	> 5 years
Dollars in thousands	**$**	$	$	$	$
Long term portion of capital lease obligation	**277**	–	277	–	–
Operating lease	**508**	174	334	–	–
	785	174	611	–	–

Changes in Accounting Policies

No new accounting policies were adopted in the year ended December 31, 2006.

Recent Accounting Pronouncements

The Canadian Institute of Chartered Accountants (CICA) has issued a number of accounting pronouncements, some of which may impact the Company's reported results and financial position in future periods.

Comprehensive Income, Financial Instruments and Hedges

The CICA issued new standards in early 2005 for Comprehensive Income (CICA 1530), Financial Instruments (CICA 3855) and Hedges (CICA 3865), which will be effective for the reporting year-end 2007. The new standards will bring Canadian rules in line with current rules in the US. The standards will introduce the concept of "Comprehensive Income" to Canadian GAAP and will require that an enterprise (a) classify items of comprehensive income by their nature in a financial statement and (b) display the accumulated balance of comprehensive income separately from retained earnings and additional paid-in capital in the equity section of a statement of financial position. Derivative contracts will be carried on the balance sheet at their mark-to-market value, with the change in value flowing to either net income or comprehensive income. Gains and losses on instruments that are identified as hedges will flow initially to comprehensive income and be brought into net income at the time the underlying hedged item is settled. Any instruments that do not qualify for hedge accounting will be marked-to-market with the adjustment (tax effected) flowing through the income statement. The Company does not anticipate these standards will have a significant impact on the Company's financial statements.

Critical Accounting Estimates

There are a number of critical estimates underlying the accounting policies the Company applies in preparing its financial statements.

Reserves

The estimate of reserves is used in forecasting what will ultimately be recoverable from the properties and their economic viability and in calculating the Company's depletion and potential impairment of asset carrying costs. The process of estimating reserves is complex and requires significant interpretation and judgment. It is affected by economic conditions, production, operating and development activities, and is performed using available geological, geophysical, engineering and economic data. Reserves at year end are evaluated by an independent engineering firm and quarterly updates to those reserves are estimated by the Company.

Revenue Estimates

Payment and actual amounts for petroleum and natural gas sales can be received months after production. The Company estimates a portion of its petroleum and natural gas production, sales and related costs, based upon information received from field offices, internal calculations, historical and industry experience.

Cost Estimates
Costs for services performed but not yet billed are estimated based on quotes provided and historical and industry experience.

Asset Retirement Obligations
The liability recorded for asset retirement obligations, an estimate of restoring assets and locations back to environmental and regulatory standards upon future retirement or abandonment, include estimates of restoration costs to be incurred in the future and an estimated future inflation rate. Costs estimated are based upon internal and third party calculations and historical experience and future inflation rates are estimated using historical experience and available economic data.

Income taxes
The Company records future tax liabilities to account for the expected future tax consequences of events that have been recorded in its financial statements. These amounts are estimates; the actual tax consequences may differ from the estimates due to changing tax rates and regimes, as well as changing estimates of cash flows and capital expenditures in current and future periods. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

Trend Analysis
Throughout 2006, the Company has been focused on drilling and completing wells, as well as tieing-in production. In the first quarter of 2006, drilling activities were delayed due to lack of rig availability. The Company alleviated the problem in the second quarter by entering into a one year contract on a drilling rig, which has facilitated the execution of the Company's 2006 third and fourth quarter drilling programs. Given the softness in the oil and gas market experienced in 2006 and into 2007, the Company does not anticipate challenges in obtaining a rig in 2007 and does not anticipate extending its drilling contract.

The Company has made strides on building a stable production base and continues to work on achieving growth, exiting the year at approximately 1600 BOE/d. Consistent with other exploration companies, there will be periods of higher production growth, periods with flush production on new wells which is then anticipated to decline and stabilize in future periods, with some periods experiencing less growth than others.

The Company's production for the year ended December 31, 2006 decreased compared to the same period of 2005 primarily as a result of the Kakwa 16-13 well which came on production in late 2004 at higher rates with production subsequently declining toward the end of 2005 and stabilizing in 2006. These declines are typical with deep, tight gas wells until decline rates stabilize. Declines in production were partially offset by production additions from 10 new producing wells in 2006.

Natural gas prices increased in the fourth quarter of 2006 compared to the second and third quarters resulting in increased revenues in the fourth quarter of 2006. The natural gas prices were still significantly lower than the prices experienced in the fourth quarter of 2005 resulting in lower revenues despite the higher production in the fourth quarter of 2006.

Natural gas liquids pricing continued to decrease in the fourth quarter of 2006 compared to the second and third quarters as well as compared to the same quarter of 2005. The increased production in the fourth quarter of 2006 helped offset the impact of the decreased liquids prices. The Company is largely impacted by price variations in the short term. Management believes in the long term strength of the natural gas market, despite short term fluctuations and volatility.

Selected Annual and Quarterly Information

(000's, except per share and production data)	Q1	Q2	Q3	Q4	Annual
2006	$	$	$	$	$
Petroleum and natural gas sales,					
net of transportation and before royalties	5,200	4,692	4,487	5,733	20,112
Funds from operations	2,475	2,406	2,115	2,970	9,966
Per share - basic	0.05	0.05	0.05	0.06	0.21
- diluted	0.05	0.05	0.04	0.06	0.20
Net income	(131)	879	(576)	(488)	(317)
Per share - basic	(0.00)	0.02	(0.01)	(0.01)	(0.01)
- diluted	(0.00)	0.02	(0.01)	(0.01)	(0.01)
Capital expenditures	6,696	13,542	7,403	9,324	36,966
Acquisition	-	-	-	-	-
Total assets	113,356	121,861	125,894	136,983	136,983
Working capital (net debt)(1)	(820)	(11,942)	(17,307)	(23,745)	(23,745)
Production (BOE/d)	1,130	1,141	1,135	1,320	1,182
2005	$	$	$	$	$
Petroleum and natural gas sales,					
net of transportation and before royalties	6,062	5,821	7,207	8,323	27,413
Funds from operations	3,198	3,037	3,908	4,899	15,042
Per share - basic	0.10	0.09	0.09	0.10	0.38
- diluted	0.09	0.08	0.09	0.10	0.36
Net income	612	537	851	1,364	3,364
Per share - basic	0.02	0.01	0.02	0.03	0.08
- diluted	0.02	0.01	0.02	0.03	0.08
Capital expenditures	6,381	8,116	9,566	11,982	36,045
Acquisition	-	-	1,220	(15)	1,205
Total assets	80,706	89,047	112,178	113,620	113,620
Working capital (net debt)(1)	(16,621)	(3,670)	10,629	3,490	3,490
Production (BOE/d)	1,421	1,264	1,262	1,245	1,297
2004	$	$	$	$	$
Petroleum and natural gas sales,					
net of transportation and before royalties	733	873	2,577	4,033	8,215
Funds from operations	190	329	1,314	1,924	3,757
Per share - basic	0.02	0.03	0.06	0.06	0.19
- diluted	0.02	0.03	0.06	0.05	0.17
Net income (loss)	(231)	11	131	189	99
Per share - basic	(0.02)	(0.00)	0.01	0.01	0.00
- diluted	(0.02)	(0.00)	0.01	0.01	0.00
Capital expenditures	1,726	1,492	1,446	11,385	16,049
Acquisition	-	-	48,625	79	48,704
Total assets	13,548	54,995	66,060	77,560	77,560
Working capital (net debt)(1)	990	109	(6,011)	(14,759)	(14,759)
Production (BOE/d)	204	216	691	981	525

Note: numbers may not cross-add due to rounding

(1) Working capital (net debt) excludes the long term financial liabilities which consists of the long term portion of the capital lease obligation [December 31, 2006 - $276,806, December 31, 2005 - $420,988, December 31, 2004 - $620,764].

Auditors' Report

To the Shareholders of Cinch Energy Corp.

We have audited the balance sheets of Cinch Energy Corp. as at December 31, 2006 and 2005 and the statements of operations and deficit and cash flows for the years then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Chartered Accountants
Calgary, Canada
March 7, 2007

Balance Sheets

As at December 31,	2006	2005
Assets *[note 6]*		
Current		
Cash and cash equivalents *[note 3]*	$ -	$ 5,654,594
Accounts receivable *[note 4]*	9,107,635	6,510,076
Prepaid expenses and deposits	957,338	752,551
	10,064,973	12,917,221
Property, plant and equipment *[note 5]*	112,301,421	86,085,917
Goodwill	14,616,996	14,616,996
	136,983,390	113,620,134
Liabilities and Shareholders' Equity		
Current		
Accounts payable and accrued liabilities	16,229,842	9,216,805
Credit facility *[note 6]*	17,304,333	-
Current portion of capital lease obligation *[note 7]*	275,789	210,007
	33,809,964	9,426,812
Capital lease obligation *[note 7]*	276,806	420,988
Asset retirement obligations *[note 8]*	2,934,899	2,725,627
Future income taxes *[note 9]*	9,410,600	7,646,760
	46,432,269	20,220,187
Commitments *[note 11]*		
Shareholders' equity		
Share capital *[note 10]*	89,618,546	93,044,644
Contributed surplus *[note 10]*	2,144,649	1,250,842
Deficit	(1,212,074)	(895,539)
	90,551,121	93,399,947
	136,983,390	113,620,134

See accompanying notes

On behalf of the board:

John W Elick

John W. Elick
Director

W D Robertson

William D. Robertson
Director

Statements of Operations and Deficit

For the years ended December 31,	2006	2005
Revenue		
Oil and gas sales	**20,900,612**	28,282,556
Transportation	**(788,794)**	(869,753)
Royalties, net of Alberta Royalty Tax Credit	**(4,110,930)**	(7,212,766)
Other income	**145,124**	155,697
	16,146,012	20,355,734
Expenses		
Operating	**3,064,713**	2,721,887
General and administrative *[note 10]*	**3,547,742**	2,748,928
Interest on credit facility	**433,677**	276,577
Interest on capital lease *[note 7]*	**27,339**	22,274
Accretion of asset retirement obligations *[note 8]*	**62,659**	157,849
Depletion and depreciation	**10,896,817**	9,256,752
	18,032,947	15,184,267
Income before income taxes	**(1,886,935)**	5,171,467
Income taxes *[note 9]*		
Current	**–**	97,650
Future	**(1,570,400)**	1,709,900
	(1,570,400)	1,807,550
Net income (loss) for the year	**(316,535)**	3,363,917
Deficit, beginning of year	**(895,539)**	(4,259,456)
Deficit, end of year	**(1,212,074)**	(895,539)
Net income (loss) for the year per share *[note 10]*		
Basic and diluted	**(0.01)**	0.08

See accompanying notes

Statements of Cash Flows

For the years ended December 31,	**2006**	2005
Operating activities		
Net income (loss) for the year	**(316,535)**	3,363,917
Add non-cash items:		
Depletion and depreciation	**10,896,817**	9,256,752
Accretion of asset retirement obligations	**62,659**	157,849
Non-cash compensation expense *[note 10]*	**893,807**	553,866
Future income taxes	**(1,570,400)**	1,709,900
	9,966,348	15,042,284
Net change in non-cash working capital	**680,757**	(722,225)
Cash provided by operating activities	**10,647,105**	14,320,059
Investing activities		
Additions to property, plant and equipment	**(36,965,708)**	(36,045,324)
Acquisition, net of cash acquired *[note 5]*	**—**	(1,204,754)
Net change in non-cash working capital	**3,616,069**	(1,937,990)
Cash used by investing activities	**(33,349,639)**	(39,188,068)
Financing activities		
Increase (decrease) in credit facility	**17,304,333**	(9,963,616)
Issue of common shares, net of issue costs	**(91,858)**	40,723,117
Payments on capital lease	**(78,400)**	(196,690)
Net change in non-cash working capital	**(86,135)**	(40,208)
Cash provided by financing activities	**17,047,940**	30,522,603
Increase (decrease) in cash	**(5,654,594)**	5,654,594
Cash and cash equivalents, beginning of year	**5,654,594**	—
Cash and cash equivalents, end of year	**—**	5,654,594
Supplemental information:		
Cash taxes paid	**—**	89,858
Cash interest paid	**411,271**	298,851

See accompanying notes

Notes to the Financial Statements

December 31, 2006 and 2005

1. DESCRIPTION OF BUSINESS

Cinch Energy Corp. (the "Company") was incorporated under the laws of the Province of Alberta and commenced operations on December 1, 2001. The Company's activities are comprised of the exploration for and development of oil and natural gas properties, primarily in Western Canada.

2. SIGNIFICANT ACCOUNTING POLICIES

These financial statements, which have been prepared in accordance with Canadian generally accepted accounting principles, have in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below.

Cash and cash equivalents

Term deposits with initial maturities less than three months are considered to be cash equivalents and are recorded at cost, which approximates market value.

Property, plant and equipment

Petroleum and natural gas properties

The Company follows the full cost method of accounting for its petroleum and natural gas activities, whereby all costs associated with the exploration for and development of petroleum and natural gas reserves, whether productive or unproductive, are capitalized in a single Canadian cost center and charged to income as set out below. Such costs can include lease acquisition, drilling, geological and geophysical, and equipment costs, and overhead expenses directly related to exploration and development activities. Proceeds from disposal of properties will normally be applied as a reduction of the cost of the remaining assets, except when such a disposal would alter the depletion rate by more than 20 percent, in which case a gain or loss will be recorded.

Ceiling test

The net carrying value of the Company's petroleum and natural gas properties is limited to an ultimate recoverable amount. The Company tests impairment against undiscounted future net revenue from proved reserves using expected future prices and costs as well as the income tax legislation in effect at the period end. Impairment is recognized when the carrying value of the assets is greater than the undiscounted future net revenues, in which case the assets are written down to the fair value of proved plus probable reserves plus the cost of unproved properties, net of impairment allowances. Fair value is determined based on discounted future net cash flows calculated using expected future prices and costs as well as the income tax legislation in effect at the period end. The discount rate used is a risk free interest rate.

Depletion

Depletion of petroleum and natural gas properties and related production equipment is provided on accumulated costs using the unit of production method based on estimated proven petroleum and natural gas reserves, before royalties, as determined by independent engineers. For purposes of the depletion calculation, proven petroleum and natural gas reserves are converted to a common unit of measure on the basis that six thousand cubic feet of natural gas is equivalent to one barrel of petroleum.

The depletion cost base includes total capitalized costs, less costs of unproven properties, plus for the estimated future development costs associated with proven undeveloped reserves.

The carrying value of undeveloped properties is reviewed periodically. The excess of carrying value of undeveloped properties over their fair value is added to costs subject to depletion.

Office furniture and equipment
Office furniture and equipment is carried at cost and depreciated on a straight-line basis over the assets' estimated useful lives at a rate of 25% per annum.

Goodwill
Goodwill represents the excess purchase price over the fair value of identifiable assets and liabilities acquired in business combinations. Goodwill is subject to ongoing annual impairment reviews, or more frequent as economic events dictate, based on the fair value of the Company's assets. The fair value of the Company's assets is determined and compared to the book value of those assets. If the fair value of the assets is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the Company's individual assets and liabilities from the fair value of the total assets to determine the implied fair value of goodwill and comparing that amount to the book value of the Company's goodwill. Any excess of the book value over the implied value of goodwill is the impairment amount.

Leases
Leases are classified as either capital or operating in nature. Capital leases are those which transfer substantially all the benefits and risks of ownership to the lessee. Assets acquired under capital leases are depleted along with the petroleum and natural gas properties. Obligations recorded under capital leases are reduced by the principal portion of lease payments as incurred and the imputed interest portion of capital lease payments is charged to expense and amortized straight-line over the life of the lease. Operating lease payments are charged to expense.

Asset retirement obligations
The Company recognizes the fair value of a liability for an asset retirement obligation and a corresponding increase in the carrying value of the related long-lived asset in the period in which they are constructed or acquired. The fair value of the obligation is management's best estimate of the cost to retire the asset based on current legislation and industry practice. The increase in the carrying value of the asset is amortized on a unit of production basis consistent with the method used to record depletion on the Company's petroleum and natural gas properties. The liability is subsequently adjusted for the passage of time, which is recognized as accretion expense in the statement of operations and deficit. The liability is periodically adjusted for revisions in either the timing or the amount of the original estimated cash flows associated with the obligation. Any difference between the related costs incurred and the recorded liability is recorded as a gain or loss in the statements of operations in the period in which the settlement occurs.

Measurement uncertainty
The amounts recorded for depletion and depreciation of petroleum and natural gas properties and other assets, the provision for asset retirement obligations, and the ceiling test calculation are based on estimates of proven or proven and probable reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

Joint operations
Substantially all of the Company's exploration and development activities are conducted jointly with others and accordingly the financial statements reflect only the Company's proportionate interest in such activities.

Flow through shares
The Company finances a portion of its exploration and development activities through the issuance of flow through shares. Under the terms of a flow through share issue, the tax attributes of the related expenditures are renounced to subscribers. To recognize the foregone tax benefits to the Company, share capital is reduced and future income taxes are increased by the tax effect of the tax benefits renounced to subscribers at the time the renouncement is filed with the tax authorities, provided there is reasonable assurance that the expenditures will be made.

Income taxes

The Company follows the liability method of accounting for income taxes. Under this method, the Company records future income taxes for the difference between the financial statement carrying value and the income tax basis of an asset or liability. Future income tax assets and liabilities are measured using substantively enacted income tax rates and laws that are expected to apply in the periods in which differences are anticipated to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in net loss in the period in which the change is substantively enacted.

Revenue recognition

Revenues from the sale of petroleum and natural gas and related products are recognized when title passes.

Stock based compensation

The Company has a stock based compensation plan, which is described in note 10. The Company has adopted the fair value based method of accounting for stock options. Stock option expense is recorded as a general and administrative expense for all options granted on or after January 1, 2003, with a corresponding increase recorded to contributed surplus. The fair value of options granted is estimated at the date of grant using the Black-Scholes valuation model. Consideration paid by employees or directors on the exercise of stock options is credited to share capital. At the time of exercise, the related amounts previously credited to contributed surplus are also transferred to share capital.

Per share information

Per share information is calculated using the treasury stock method. Under this method, the diluted weighted average number of common shares is calculated assuming that the proceeds from the exercise of outstanding and in the money options is used to purchase common shares at the estimated average market price.

3. CASH AND CASH EQUIVALENTS

As at December 31, 2006, the Company had drawn on its $33 million credit facility (see note 6) and, accordingly, had no cash and cash equivalents [December 31, 2005 - cash and cash equivalents included term deposits with maturities of 90 days or less of $4,980,000, which earned interest at 2.78%].

4. ACCOUNTS RECEIVABLE

A substantial portion of the Company's accounts receivable is with oil and gas marketing entities. The Company generally extends unsecured credit to these companies, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Company's overall credit risk. Management believes the risk is mitigated by the size, reputation and diversified nature of the companies to which they extend credit.

The Company has not previously experienced any material credit losses on the collection of receivables. Of the Company's significant individual accounts receivable at December 31, 2006, approximately 91% was owed from 6 customers (December 31, 2005 - 65% was owed from 7 customers).

5. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment

	December 31, 2006		
	Cost $	Accumulated depreciation $	Net book value $
Petroleum and natural gas properties	**141,281,753**	**(29,905,549)**	**111,376,204**
Equipment under capital lease	**1,020,307**	**(188,179)**	**832,128**
Office furniture and equipment	**240,570**	**(147,481)**	**93,089**
	142,542,630	**(30,241,209)**	**112,301,421**

	December 31, 2005		
	Cost $	Accumulated depreciation $	Net book value $
Petroleum and natural gas properties	104,375,911	(19,153,951)	85,221,960
Equipment under capital lease	839,303	(95,777)	743,526
Office furniture and equipment	215,095	(94,664)	120,431
	105,430,309	(19,344,392)	86,085,917

For the years ended December 31, 2006 and 2005, no indirect general and administrative expenditures were capitalized.

As at December 31, 2006, $10,900,069 of costs related to undeveloped lands were excluded from costs subject to depletion [December 31, 2005- $11,885,839]. As at December 31, 2006, the depletion calculation included future development costs of $3,264,000 [December 31, 2005 - $3,241,000].

Acquisition

Effective August 4, 2005, the Company acquired all of the issued and outstanding common shares of and wound up 1008742 Alberta Ltd. into Cinch Energy Corp. The certificate of dissolution was received December 21, 2005. The total cash consideration of the purchase was $1.205 million which was allocated to petroleum and natural gas properties, future taxes and working capital. The acquisition was accounted for using the purchase method and therefore revenues and expenses from the acquired assets were included in the statements of operations and deficit from August 4, 2005.

The purchase price was allocated as follows:

	$
Non-cash working capital	38,852
Land	1,421,639
Property, plant and equipment	93,648
Asset retirement obligation	(6,678)
Future taxes	(342,707)
Total purchase price	1,204,754

The Company has performed an impairment test as of December 31, 2006 using the estimated average price for each of the next five years as determined by the Company's independent reserve engineers adjusted for differentials specific to the Company's reserves as follows:

	Natural Gas Cdn $/mmbtu	Natural Gas Liquids Cdn $/bbl
2007	7.00	71.75
2008	7.25	69.25
2009	7.55	67.00
2010	7.60	65.75
2011	7.65	65.75
Each benchmark price increased on average approximately 2% from 2012 and thereafter		

There was no impairment at December 31, 2006.

6. CREDIT FACILITY

As at December 31, 2006, the Company had a demand, bank credit facility through ATB Financial of $33,000,000 [December 31, 2005 - $26,500,000]. The facility bears interest at the lender's prime rate. The effective interest rate at December 31, 2006 was 6.09% [December 31, 2005 - 4.02%]. As at December 31, 2006, there was $17,300,000 drawn on the credit facility [December 31, 2005 - nil]. As collateral for the facility, the Company has provided a general security agreement with the lender constituting a first ranking security interest in all personal property and a first ranking floating charge on all real property of the Company subject only to a subordination agreement to another bank for the amount of, and as security for, a capital lease (see note 7).

7. CAPITAL LEASE OBLIGATION

The Company is committed to annual minimum payments under a capital lease agreement which commenced in December, 2004, as follows:

Years ending December 31,	$
2007	304,855
2008	304,855
Total minimum lease payments	609,710
Less amounts representing interest at 5.12%	(57,115)
Present value of minimum lease payments	552,595
Less current portion	(275,789)
Long term portion of capital lease obligation at December 31, 2006	276,806

For the year ended December 31, 2006, there was $27,339 [2005 - $22,274] recorded in interest expense relating to capital leases. A first charge on the Company's assets has been provided as security for the capital lease obligation.

8. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligations result from the Company's net ownership interest in wells and facilities. Management estimates the total undiscounted amount of future cash flows required to reclaim and abandon wells and facilities as at December 31, 2006 is approximately $5,300,000 to be incurred over the next 43 years [December 31, 2005 - $4,260,000]. The Company used a credit adjusted, risk-free rate ranging from 5% to 7.5% and an inflation rate of 2% to arrive at the recorded liability of $2,934,899 at December 31, 2006 [December 31, 2005 - $2,725,627]. The December 31, 2006 balance reflects adjustments recorded in 2006 to the estimated abandonment dates of some of the wells. The estimated dates were revised and extended to better reflect the economic life of the wells, effectively reducing the present value of the liability when compared to December 31, 2005, offset by the additions for the year ended December 31, 2006.

The Company's asset retirement obligations changed as follows:

	December 31, 2006	December 31, 2005
	$	$
Asset retirement obligations, beginning of year	**2,725,627**	1,633,234
Adjustment to abandonment dates	**(304,622)**	6,678
Liabilities incurred	**451,235**	927,866
Accretion expense	**62,659**	157,849
Asset retirement obligations, end of year	**2,934,899**	2,725,627

9. FUTURE INCOME TAXES

Income tax recovery differs from the amount that would be computed by applying the Federal and Provincial statutory income tax rates to loss before income taxes. The reasons for the differences are as follows:

	December 31, 2006	December 31, 2005
Statutory income tax rate	34.49%	37.62%
	$	$
Anticipated income tax expense (recovery)	(650,804)	1,945,506
Increase/(decrease) resulting from:		
Resource allowance	(450,826)	(1,406,352)
Non-deductible crown royalties, net of ARTC	274,700	1,160,585
Non-deductible items	-	5,512
Stock based compensation expense	308,274	208,364
Rate adjustment	(1,051,744)	(203,715)
Future income tax expense (recovery)	(1,570,400)	1,709,900
Large corporations tax	-	97,650
	(1,570,400)	1,807,550

Future income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts for income tax purposes. The components of the Company's future income tax assets and liabilities are as follows:

	December 31, 2006	December 31, 2005
	$	$
Net book value of capital assets in excess of tax pools	(11,051,577)	(9,663,114)
Share issue costs	649,182	1,047,675
Asset retirement obligations	886,339	916,356
Other	105,446	52,323
Future income taxes	(9,410,610)	(7,646,760)

10. SHARE CAPITAL

Authorized - Unlimited number of common voting shares without par value

	December 31, 2006		December 31, 2005	
Issued	Number	$	Number	$
Common shares				
Balance, beginning of year	47,757,632	93,010,709	33,104,316	51,568,073
Issued for cash on warrant exercise (i)	-	-	8,022,529	19,053,506
Issued for cash on flow through private placement (ii)	-	-	2,352,941	9,999,999
Issued for cash on private placement (ii)	-	-	3,676,472	12,500,005
Exercise and conversion of special warrants (iii)	-	-	257,600	238,759
Issued for cash on options exercise (iv)	-	-	100,334	188,126
Issued for cash on brokers' warrant exercise (v)	-	-	243,440	243,440
Reclassification on exercise of options (iv)	-	-	-	56,473
Tax effect of flow through common share renunciation (ii)	-	(3,362,000)	-	-
Issue costs, net of future taxes	-	(64,098)	-	(837,672)
Balance, end of year	47,757,632	89,584,611	47,757,632	93,010,709
Special warrants				
Balance at beginning and end of year	55,000	33,935	55,000	33,935
Share capital, end of year	47,812,632	89,618,546	47,812,632	93,044,644

	2006	2005
Contributed surplus		
Balance, beginning of year	1,250,842	753,449
Non cash compensation expense (iv)	893,807	553,866
Reclassification to share capital on exercise of options (iv)	-	(56,473)
Contributed surplus, end of year	2,144,649	1,250,842

Common Shares

(i) Warrant exercise

In 2005, a total of 8,022,529 common shares were issued pursuant to the exercise of warrants at an exercise price of $2.375, for gross proceeds of $19,053,506.

(ii) Private Placement

On September 8, 2005, the Company issued under private placement a total of 2,352,941 flow through common shares at $4.25 per share for proceeds of $9,999,999 and 3,676,472 common shares at $3.40 per share for proceeds of $12,500,005 before total issues costs of $1,203,880. The expenditures were renounced, in their entirety, in February, 2006 and the tax benefits thereon, in the amount of $3,362,000 was recorded on that date.

(iii) Exercise of special warrants

During the year ended December 31, 2005, special warrant holders exercised 257,600 special warrants in exchange for a total of 257,600 common shares for no additional cash consideration.

(iv) Exercise of options

During the year ended December 31, 2005, a total of 100,334 common shares were issued on exercise of stock options at an average exercise price of $1.875. As a result, stock compensation expense of $56,473 previously recognized for these options was reclassified from contributed surplus to common shares.

The non-cash compensation expense is comprised of the stock option benefit for all outstanding options.

(v) Brokers' warrant exercise

During the year ended December 31, 2005, a total 243,440 common shares were issued pursuant to the exercise of brokers' warrants at an exercise price of $1.00. There are no brokers' warrants outstanding.

Per share amounts

Per share amounts have been calculated using the weighted average number of common shares and special warrants outstanding during the year of 47,812,632 [2005 - 40,046,588]. As at December 31, 2006, the options are anti-dilutive and therefore the diluted per share amount is not presented based on the diluted weighted average number of common shares outstanding of 49,187,756. [December 31, 2005 - the diluted weighted average number of common shares outstanding was 41,921,643 and the diluted per share amounts were calculated assuming the exercise of outstanding, in-the-money options, and future compensation costs to be incurred on outstanding options]. For the year ended December 31, 2006, per share calculations are anti-dilutive and are not presented based on outstanding, out-of-the-money options [December 31, 2005 - 125,000 options].

Stock option plan

The Company has a stock option plan authorizing the grant of options to purchase shares to designated participants, being directors, officers, employees or consultants. Under the terms of the plan, the Company may grant options to purchase shares equal to a maximum of ten percent of the total issued and outstanding shares and special warrants of the Company. The aggregate number of options that may be granted to any one individual must not exceed five percent of the total issued and outstanding shares and special warrants. Options are granted at exercise prices equal to the estimated fair value of the shares at the date of grant and may not exceed a ten year term. The vesting for options granted occurs over a three year period, with one third of the number granted vesting on each of the first, second, and third anniversary dates of the grant unless otherwise specified by the Board of Directors at the time of grant.

The following is a continuity of stock options for which shares have been reserved:

	2006		2005	
	Number of Options	**Weighted Average Exercise Price**	Number of Options	Weighted Average Exercise Price
		$		$
Stock options outstanding, beginning of year	**2,328,000**	**2.17**	1,635,000	1.88
Granted	**2,141,000**	**1.75**	1,065,000	2.55
Exercised	**-**	**-**	(100,334)	1.88
Cancelled/Expired	**(397,666)**	**2.11**	(271,666)	2.00
Stock options outstanding, end of year	**4,071,334**	**1.96**	2,328,000	2.17

Stock options outstanding at the end of the year are comprised of the following:

December 31, 2006			December 31, 2005		
Exercise Price	**Number of Options**	**Number of exercisable options**	Exercise Price	Number of Options	Number of exercisable options
$			$		
1.24-1.50	**895,000**	**-**	1.24-1.50	-	-
1.51-2.00	**1,338,000**	**888,998**	1.51-2.00	1,308,000	610,666
2.01-2.50	**1,125,000**	**81,666**	2.01-2.50	265,000	20,000
2.51-3.00	**588,334**	**184,999**	2.51-3.00	630,000	-
3.01-3.50	**125,000**	**41,667**	3.01-3.50	125,000	-
1.96	**4,071,334**	**1,197,330**	2.17	2,328,000	630,666

The options outstanding at December 31, 2006 have a weighted average remaining contractual life of 3.6 years [December 31, 2005 - 3.7 years].

The fair value of stock options granted to employees, directors and consultants during the year ended December 31, 2006 and 2005, was estimated on the date of grant using the Black Scholes option pricing model with the following weighted average assumptions: dividend yield of zero percent [2005 - zero percent], expected volatility of 47.95 percent [2005 - 34.62 percent], risk-free interest rate of 3.95 percent [2005 - 3.43 percent], and an expected life of four years [2005 - four years]. Outstanding options granted during the year ended December 31, 2006 had an estimated weighted average fair value of $0.73 per option [December 31, 2005 - $0.83 per option], for a total estimated value of $1,556,600 [2005 - $827,890]. For the year ending December 31, 2006, a total of $893,807 [2005 - $553,866] has been recognized as stock compensation expense in general and administrative expenses with an offsetting credit to contributed surplus.

11. COMMITMENTS

The Company has entered into an operating lease for office premises expiring on November 20, 2009, which requires minimum monthly payments of $14,520 for the remainder of the lease.

The Company has entered into a capital lease obligation, as more fully described in note 7.

12. FINANCIAL INSTRUMENTS

Fair value of financial instruments

Financial instruments recognized on the balance sheet consist of cash and cash equivalents, accounts receivable, deposits, accounts payable, credit facility and capital lease obligations. As at December 31, 2006 and 2005, there were no significant differences between the carrying amounts of these financial instruments reported on the balance sheet and their estimated fair values. It is management's opinion that the Company is not exposed to significant credit risk.

Interest rate risk

The Company is exposed to interest rate risk relating to increases in interest rates on its variable rate credit facility.

Commodity price risk management

As at December 31, 2006, the Company had no fixed price contracts associated with future production.

13. BASIS OF PRESENTATION

Certain of the comparative figures have been reclassified to conform to the presentation adopted in the current year.

14. SUBSEQUENT EVENT

On February 21, 2007, the Company issued 7,812,500 common shares on a flow through basis at a price of $1.28 per share for gross proceeds of $10,000,000.

From Left:
Ian Weitz, Senior Geologist,
John W. Elick, Chief Executive Officer,
Terry McLellan, Accounting Supervisor,
Jason Yuen, Senior Production/Revenue Accountant

Corporate Information

From Left:
Brian McBeath, Vice President Exploration,
Barb Cook, Office Manager

Board of Directors

John W. Elick(3)
Chief Executive Officer, Cinch Energy Corp.

George Ongyerth(2)
President, Cinch Energy Corp.

Sid W. Dykstra(1),(2),(3)
President and Chief Executive Officer of OPTI Canada Inc.

William D. Robertson(1),(2),(4)
Director, Cinch Energy Corp.

Gerald M. Deyell, Q.C.(1),(3),(4)
Partner, Blake, Cassels & Graydon LLP

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee
(3) Member of the Compensation Committee
(4) Member of the Corporate Governance Committee

Officers

John W. Elick
Chief Executive Officer

George Ongyerth
President

Brian J. McBeath
Vice President, Exploration

Denise A. Ramage
Chief Financial Officer

Marcus McLafferty
Vice President, Land

C. Steven Cohen
Secretary

Sarah Tait
Controller

Managers

Larry Baker
Drilling and Completions Manager

Barb Cook
Office Manager

Ron Peshke
Engineering Manager

Neil Rutherford
Manager of Geophysics

Officers Registrar and Transfer Agent

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Banker

ATB Financial
Calgary, Alberta

Auditors

Ernst & Young LLP
Calgary, Alberta

Independent Engineers

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Legal Counsel

Burnet, Duckworth & Palmer LLP
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